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Cost and U.S. public policy for new coal power plants with carbon capture and sequestration

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Abstract

This paper provides a financial analysis for new supercritical pulverized coal plants with carbon capture and sequestration (CCS) that compares the effects of two relevant climate policies. First, an updated cost estimate is presented for new supercritical pulverized coal plants, both with and without CCS. The capital cost escalation of recent years can be attributed to rising materials, plant supply, and plant contractor constraints. This estimate is then compared with recent estimates from public sources. Second, several current and proposed public policies relevant to CCS are presented. Finally, a financial analysis is performed to evaluate the effectiveness of two likely US carbon regulations on deploying Nth-plant CCS technology. The major conclusion is that the leading US carbon cap-and-trade bills will likely not be sufficient to deploy CCS technology in a manner consistent with a 550ppm CO_2 stabilization scenario. A more aggressive carbon policy including CCS research, development, and demonstration must be considered to achieve this goal with significant CCS deployment.

Keywords: carbon capture and sequestration; CCS; financing electric power plants; United States climate change policy;

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1. Introduction

Given the billion-dollar investment scale of base load power plants, accurate financial decision-making must be performed by utilities and investors when making build decisions for new generation. After years of research and high hopes, carbon capture and sequestration (CCS) technology for coal generation remains prohibitively expensive, and it remains unlikely that CCS will be financed commercially for years to come. Public policies regulating carbon dioxide or supporting low-carbon technologies could help push CCS toward commercial viability, therefore the cost-competitiveness of new plants with CCS is highly dependent on future policy direction.

This paper provides a financial analysis for new supercritical pulverized coal (SCPC) plants with CCS that compares the effects of two relevant climate policies. First, an updated cost estimate is presented for new supercritical pulverized coal plants, both with and without CCS. This estimate is compared with costs estimates from public sources. Second, several current and proposed public policies relevant to CCS are discussed. Finally, a financial analysis is performed to evaluate the effectiveness of two likely US carbon regulations on deploying Nth-plant CCS technology. The conclusion is that the leading US carbon cap-and-trade bills will likely not be sufficient to deploy CCS technology in a manner consistent with global CO_2 emissions reduction scenarios. A more strict carbon regulation and a more aggressive R&D and demonstration program for reducing the cost of CCS must also be considered.

2. Cost Update for Nth-Plant Supercritical Coal

2.1. Recent cost escalation

Since 2004, the capital and operating costs of new power plants have risen sharply for all types of power plants, including new coal plants with and without carbon capture and sequestration (CCS). To account for this recent cost escalation, we have updated the cost estimates originally presented in *The Future of Coal* [1]. Figure 1 shows several cost and price indices from 2000 to 2007 as an example of this recent price escalation.

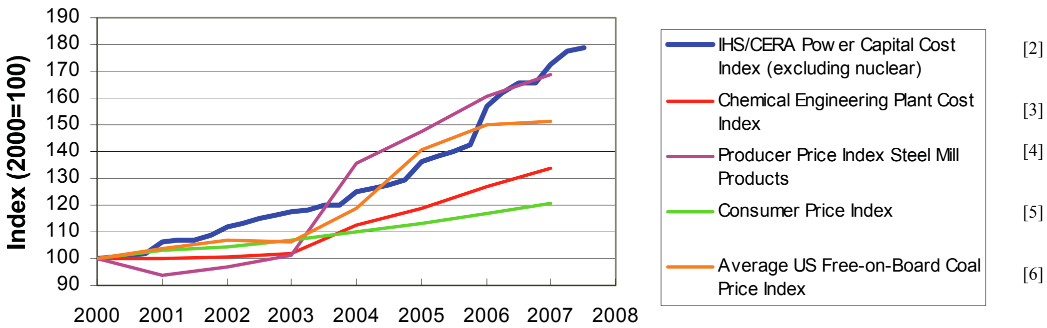

Figure 1. Cost and Price Indices since 2000.

There are several reasons for this escalation in costs [7]:

- Increasing global demand for the raw materials required to build new plants such as steel, cement, copper, and nickel.
- High international plant demand has increased prices for plant components, such as turbines, boilers, and scrubbers, due to vendor capacity limitations.
- Engineering, labor, and construction costs are all increasing as well. Engineering, procurement, and construction (EPC) contractor backlogs are becoming more common.
- Coal fuel price has increased significantly in the US; this increase is probably due to increasing demand under rail shipping capacity constraints and increased US coal exports.

The release of *The Future of Coal* in March 2007 included a cost estimate for new coal plants [8]. This cost estimate was derived from an extensive review of plant design studies from 2000-2004 then standardized for capacity factor, capital charge, and fuel price and then updated to 2005$ using the consumer price index (CPI). This information was combined with expert opinion and reviewed by technology providers and others to arrive at the final cost estimate. Cost escalation since 2000 was acknowledged in the original report, but was not accounted for in the final cost estimate.

2.2. Cost Update

Given the significant public influence of *The Future of Coal* report [8], we acknowledge the importance in updating our cost estimates now, despite continuing cost escalation. We are only updating the costs for supercritical pulverized coal (SCPC) here, since the recent literature and discussion with industry experts support these new estimates. New cost estimates for integrated gasification-combined cycle (IGCC) and oxy-fuel combustion technology are not being presented here for two reasons. One reason is the tremendous uncertainty in the true costs and performance characteristics of such new technology. The second reason is that our discussion with industry experts indicates that any current IGCC cost estimate is highly uncertain since costs for IGCC may have doubled or tripled since 2004. To present a new estimate under such high uncertainty would be detrimental to the discussion about new generation technology. This situation underscores the importance for new comprehensive design and cost studies reflecting the new technical knowledge about IGCC in this transient cost environment.

Our estimate of costs for SCPC has been updated to a 2007$ basis according to estimates of recent escalation in capital, operating, and fuel costs. Our updated cost estimate is shown in Table 1.

Due to the recent cost escalation for power projects, as well as insight from comparison with recently published cost data, we must acknowledge a low level of certainty about this updated cost estimate. While we have attempted to account for recent cost escalation in a transparent manner, our attempt is akin to trying to hit a moving target; we are currently in a highly volatile market and costs are constantly changing.

Table 1. Updated Costs for Nth Plant SCPC Generation

		Units	SCPC
Reference Plant			
Total Plant Cost (1)		\$/kWe	1910
CO_2 emitted		kg/kWh	0.830
Heat Rate (HHV)		Btu/kWh	8868
Thermal Efficiency (HHV) (2)			38.5%
LCOE	Capital (3)	\$/MWh	38.8
LCOE	Fuel	\$/MWh	15.9
LCOE	O&M	\$/MWh	8.0
LCOE	Total	\$/MWh	62.6
CO_2 Capture Plant			
Total Plant Cost (1)		\$/kWe	3080
CO_2 emitted @ 90% Capture		kg/kWh	0.109
Heat Rate (HHV)		Btu/kWh	11652
Thermal Efficiency (HHV) (2)			29.3%
LCOE	Capital (3)	\$/MWh	62.4
LCOE	Fuel	\$/MWh	20.9
LCOE	O&M	\$/MWh	17.0
LCOE	Total	\$/MWh	100.3
\$/tonne CO_2 avoided			
vs. SCPC (4)		\$/tonne	52.2

The capital costs were escalated with the IHS/CERA Power Capital Costs Index (PCCI) for Coal Power [2]. The original values were deflated from 2005$ to 2002$ using a CPI index as reported in Table A-3.C.5 in the *The Future of Coal* [8]. The values were then escalated by to 2007$ using the CERA PCCI, from 112 in 2002 to 172 in 3rd quarter 2007. This represents an increase of 44% in capital costs as compared to the original data.

The fuel costs for bituminous Illinois #6 coal have also increased from $1.50/MMBtu delivered cost to $1.79/MMBtu in 2007. This data was collected from the quantity-weighted average price of delivered coal from the Illinois basin in 2007 from FERC Form 423 data. This represents an increase of 19% in fuel price as compared to the original assumption.

The operations and maintenance (O&M) costs were scaled by the CPI index from 195.3 in 2005 to 207.3 in 2007. The CPI data is from the US Bureau of Economic Analysis. This represents and increase of 6% in O&M costs since 2005.

2.3. Comparison of Capital Costs with Recent Data

In Table 2, there is a comparison of this updated capital cost estimate with several publicly available sources, including design studies as well as actual plant estimates from recent press releases and PUC filings from 2007 and 2008. The capital cost numbers are presented in $/kW on a total plant cost (TPC) basis where possible, except for the actual plant estimates which are on an unknown cost basis.

Table 2. Capital Cost Comparison

Fuel Type	Estimate Type	Estimate Name	Date	Total Plant Cost ($/kW) (where possible) SCPC	SCPC w/CCS	IGCC	IGCC w/CCS	Oxy-PC
Bituminous	Design Studies	MIT Update		$1,910	$3,080			
		CERA [9] [2]	Mar 2008	$2,300	$4,150	$2,800	$4,230	$4,230
		NETL [10]	May 2007	$1,575	$2,870			$2,895
		S&P [11] [3]	May 2007	$2,216	$3,071	$2,541	$2,950	
		NETL GE [10]	May 2007			$1,813	$2,390	
		NETL Conoco Phillips [10]	May 2007			$1,733	$2,431	
		NETL Shell [10]	May 2007			$1,977	$2,668	
	Actual Plant Estimates [12]	Duke - Cliffside, NC	May 2007	$3,000				
		Duke - Edwardsport, IN	May 2008			$3,730		
		AEP - Mountaineer, WV	June 2007			$3,545		
		Tampa Electric - Polk Co., FL	July 2007			$2,554		
Sub-bituminous	Design Studies	EPRI [13]	Oct 2006	$1,950	$3,440	$2,390	$3,630	
		BERR/CPCC [14] [4]	Mar 2007	$2,618	$4,445			$4,586
		S&P [11]	May 2007			$2,659	$3,068	
	Actual Plant Estimates [12]	AEP/SWEPCO -Hempstead, AR	Dec 2006	$2,800				
		Sunflower - Holcomb, KS	Sep 2007	$2,572				
		AMP Ohio - Meigs Co. OH	Jan 2008	$3,300 – note uses both bit. and PRB coal				
		Tenaska - Sweetwater Co., TX	Feb 2008		$5,000			
		Southern Co. - Kemper Co., MS	Dec 2006			$3,000		

The following general conclusions were reached:

- Our updated cost estimate for SCPC is within the range of recently reported design studies, but is consistently lower than each of the actual plant estimates, which is expected since we estimate for Nth plant design.
- Our updated cost estimate is generally lower than the S&P and CERA estimates, but higher than the NETL estimate. Note the large variance in the cost data within each plant type; this variance supports the fact that there is no current consensus on power plant costs.
- With few exceptions, the actual plant estimates report costs significantly higher than the design study estimates.

While we would expect actual plant estimates for the first generation of plant with little construction experience (i.e. SCPC w/ CCS, IGCC w/o and w/CCS, and Oxy-PC) to exhibit a "first-of-a-kind" cost premium, we would not expect SCPC reference case to show such high costs. Given the lack of construction and operating experience, we would expect the public estimates to be much higher than design study estimates since the many of these actual plant estimates reflect first-of-a-kind costs, which generally agrees with our observations.

To the contrary, for SCPC, the actual plant estimates generally show much higher costs than the design study estimates. SCPC plants use mature technology with significant operating experience; EPC contractor guarantees for cost and performance are available. Despite this experience with SCPC, it seems that the external factors of materials cost escalation and high market demand for new plant construction have outstripped even the most recent published studies attempting to quantify the recent cost escalation.

2.4. Conclusion on cost update

We have made a transparent attempt to update the cost data from *The Future of Coal*, and we acknowledge the uncertainty in our final outcome. Our cost estimate was updated by including escalation factors for capital costs, operations, and fuel costs. There is speculation that this recent cost escalation is a temporary market-driven bubble, and that costs will return to a lower stable level when either supply of commodities, components, and fuel increases to meet the recent rising demand or if global demand for these items decreases. Some also speculate that this escalation is not a bubble, but rather a new reality of a globalizing economy. Early indications of a slowing global economy in late 2008 may support the argument that demand is

2 Adjusted downward from all-in capital cost (which includes owner's costs, etc.) assuming all-in cost is 30% greater than total plant cost per EPRI TAG methodology.

3 Adjusted downward from all-in capital cost assuming all-in cost is 10% greater than engineering, procurement, and construction (EPC) cost (assumed to be equivalent to TPC)

4 Adjusted downward from total capital requirement (TCR) assuming TCR is 10% greater than TPC

decreasing and that capital costs may stabilize. Either way, the many uncertainties in the cost and market characteristics for new power generation technology show that a more comprehensive attempt to quantify and explain this recent cost escalation is sorely needed.

3. Major US Greenhouse Gas Legislation Options

3.1. Recent US Federal activity affecting CCS

The recent US activity federal activity affecting CCS technology has been a continuation of research and development programs, pilot-scale demonstrations for sequestration, and two major investment tax credits. Over the past few years, the Department of Energy has continued to receive support from Congress for several programs supporting CCS. The Office of Fossil Energy continues to implement the research and development program, mostly through the National Energy Technology Laboratory and the Clean Coal Power Initiative, as well as grant programs for academic and private R&D projects. The DOE also has seven Regional Partnerships to demonstrate sequestration at the 1MtCO_2/yr level. Currently, these partnerships are at varying stages, with most in the pilot scale testing phases.

The DOE is also working to demonstrate full-scale integrated CCS for electricity through the FutureGen project, a major integrated CCS demonstration program still under development. Currently, the project will support the cost of CCS equipment for several integrated CCS plants. Originally, the project would have been the first integrated carbon capture and sequestration project in the US and possibly in the world. It would have been a 275MW IGCC coal power plant with saline formation sequestration at a site in Mattoon, IL. As of September 2008, The FutureGen Alliance, the industry consortium leading the original FutureGen project, is still pursuing US congressional funding for the project independent of the DOE's restructured FutureGen plans [15].

The two major investment tax credits relevant to CCS are the Advanced Coal Project Investment Credit and the Coal Gasification Investment Credit. Originally these tax credits were introduced as part of the Energy Policy Act of 2005. This program provided up to \$800m for IGCC projects and \$500m for advanced coal-based generation technologies over three years. Details of the awarded projects can be found at [16].

3.1.1. CCS and Coal Provisions in "Bailout" Bill

In response to the credit crisis in 2008, the US congress passed a bill H.R. 1424 entitled the Emergency Economic Stabilization Act of 2008. Besides providing authorization for up to \$700b to help ease the effect of the credit crisis on the US financial industry, the bill also included several notable energy provisions with some specifically relevant to advanced coal and CCS technology.

The bill contains a modification to both the Advanced Coal Project Investment Credit and the Coal Gasification Investment Credit. The updated Advanced Coal Project Investment Credit program extends the period of application by three years, and provides an additional \$1.25b for advanced coal projects capturing and sequestering at least 65% of their CO_2 emissions. Up to 30% of the project cost can be awarded the tax credit. The updated Coal Gasification Investment Credit program provides an additional \$250m for gasification demonstration projects that capture and sequester at least 75% of their CO_2 emissions. The new program also allows credit for gasification projects producing liquid fuels for transportation.

The bill also provides a new tax credit for sequestration of CO_2 in secure geological storage or for enhanced oil and gas recovery projects. For facilities capturing more than 500,000 tonne (t) of CO_2 /yr, a \$20/tonne tax credit can be applied to sequestration in secure geological storage which includes deep saline formations and unminable coal seams and a \$10/tonne tax credit can be applied to sequestration for purposes of enhanced oil and gas recovery. This credit will apply for the first 75Mt of CO_2 sequestered. This credit will likely help support some early private-sector CCS demonstration projects.

3.2. Proposed US legislation

There have been numerous attempts to formulate a winning climate bill in the US congress over the past several years. The policy mechanisms proposed in these bills to limit greenhouse gas emissions vary widely. Carbon taxes, emissions performance standards, portfolio standards, cap-and-trade systems, direct subsidies, indirect subsidies such as tax credits, and clean technology R&D have all been proposed, often in combination with each other. Which policy tools will be politically viable remains to be seen.

While it is common sense to understand that CCS technology will only be deployed in the presence of a price on carbon, there is much disagreement on what price would be sufficient versus what price would be likely given the current political atmosphere. Combined with the cost update in Section 2 of this paper, an audit of the major current policy approaches affecting CCS will allow some conclusions to be reached about the likelihood of CCS to be deployed under these varying policy scenarios.

3.2.1. US Climate Legislation

3.2.1.1. Lieberman-Warner Climate Security Act of 2008

The leading piece of climate legislation being considered in 2008 is S.3036, the Lieberman-Warner Climate Security Act of 2008. This bill would establish a cap-and-trade program for greenhouse gas emissions from all major emitting sector including both electricity and vehicle transportation. The eventual target would be 70% below 2005 emissions levels by the year 2050. This target is similar to goals recommended by climate scientists to achieve a 450ppm CO_2 concentration stabilization. A Carbon Market Efficiency Board would be established a sort of "central bank" for carbon markets that could act to contain costs if needed; the most important function of this board would be to allow expanded borrowing of future allowances and/or international offsets (such as CDM credits) if the US economy was in a crisis.

There are several notable details in this bill specific to CCS. Initially, 18% of emissions allowance would be freely allocated to the power generation sector, with this amount reduced to zero by 2031. The remainder of emissions allowances would need to be bought through government auction or private purchase in an emissions allowance market.

There will be bonus allowances given to power generators choosing to use CCS. The bonus will be 4.5x in 2012 reduced to zero by 2033. These bonus allowances would be valid for the first 10 years of operation of the CCS plant. For example, for each ton of CO_2 sequestered in 2012, the company would receive one allowance plus 4.5 additional emissions allowances to either sell or use for their other CO_2 emitting plants. There is an emissions standard required to receive this bonus. New plants with CCS must emit less than 800 $lbCO_2/MWh$ before 2018, and after 2018, a new plant must emit less than 300 $lbCO_2/MWh$. Plants choosing to retrofit with CCS must emit less than 1200 $lbCO_2/MWh$.

Since this program will likely be generating hundreds of billions of dollars of auction revenue every year, a major part of S.3036 is the allocation of this massive fund toward various projects, including CCS technology. In total, 25% of auction proceeds will go to advanced coal and CCS demonstration, with at least 6.25% to advanced coal and 12.5% to CCS demonstration. In total this bill would likely support 5-10 CCS demonstration plants through these revenues.

3.2.1.2. Low Carbon Economy Act of 2007

Another major piece of climate legislation is S.1766, the Low Carbon Security Act of 2008 or the "Bingaman-Specter" bill. This bill is based upon final recommendations from the National Commission on Energy Policy. This bill would also establish a cap-and-trade program for greenhouse gas emissions. The target would be to reach 1990 emissions levels by the year 2030. This bill has a cost-containment mechanism called TAP – "Technology Accelerator Payment"; if the market price reaches the current TAP price, then emitters can purchase credits from the government at the TAP price. The TAP starts at $10 in 2012 increasing to ~$25 in 2030 (not including inflation). TAP proceeds would go into a fund to support energy technology deployment.

Initially, 28.6% of emissions allowances would be freely allocated to the power generation sector, with this amount reduced to zero by 2043. Similarly to S.3036, this bill also includes bonus allowances given to power generators choosing to use CCS. The bonus will be 3.5x in 2012 reducing to zero by 2040. These bonus allowances would be valid for the first 10 years of operation of the CCS plant. Similar to S.3036, there will be billions in auction proceeds available for energy projects. In total, 5.5% of auction proceeds will go to advanced coal demonstration, 5.5% to commercial CCS deployment, and 11% for early CCS demonstration projects.

3.2.2. CCS Demonstration Support

3.2.2.1. CCS Trust Fund

The concept of a trust fund for CCS demonstration projects has been gaining traction recently. Popularized by Prof. Ed Rubin of Carnegie Mellon, the idea would be to charge a small fee per kWh to every electricity consumer in the country. The fee collected would then be put into a trust fund designated for funding CCS demonstration projects.

The first legislative embodiment of this idea was recently proposed by Rep. Boucher of Virginia as H.R.6258. This bill would impose a small fee on all fossil power sales for 10 years. The fee would be 0.43 mill/kWh for coal-fired generation, 0.22 mill/kWh for gas, and 0.32 mill/kWh for oil. This fund would aggregate into about $1 billion annually, which would be about $10 billion over 10 years. This fund would be managed by a Carbon Storage Research Corporation, which would be a division of the Electric Power Research Institute. The managing board would be staffed by power industry representatives, with the mission of supporting 3-5 large-scale commercial demonstrations of CCS. The major advantage to this approach would be avoiding the political appropriations process, as well as federal procurement requirements that a DOE-managed project would have to follow.

3.2.2.2. Energy Technology Corporation

A second idea for demonstration is an Energy Technology Corporation. Recently proposed by John Deutch, John Podesta, and Peter Ogden [17], this corporation would be a semi-private corporation funded by a large single appropriation to fund energy technology demonstrations for technologies like CCS and cellulosic ethanol production. The corporation would be managed by a board appointed by President. No detail as to the level of initial funding required has been proposed. Similar to the CCS trust fund option, this corporation would be independent of federal procurement rules and the yearly appropriations process.

One criticism of this approach is due to the problems encountered by the US Synthetic Fuels Corporation in the early 1980s. The Synfuels Corporation was created in response to the oil shocks of the 1970s with the mission of increasing US energy independence through coal-to-liquids technology. The Corporation was created with fixed production targets, which ultimately led to billions of dollars of spending on projects producing fuel at a cost several times higher than the then market-price of automotive fuel. Proponents of a new Corporation for energy projects say that technology progress targets would either be flexible and reviewed periodically, so that demonstration priorities could be shifted if changing market conditions justified the shift, or they could be based on cost and performance rather than production targets, which would hopefully help avoid the problems encountered by the Synfuels Corporation.

3.2.2.3. Clean Energy Investment Bank

A third proposal for CCS demonstration is a Clean Energy Investment Bank. As proposed in S.2730 by Sen. Pete Domenici of New Mexico, this would be a federally-funded bank to provide financial services for clean energy projects. After receiving a large initial endowment for a "clean energy investment bank fund" from the federal government, it would act as normal investment bank acts, by providing loan guarantees, insurance, loans, equity and security investment, and other services. This bank would be backed by full faith and credit of US government. The bank will be managed as a bank by an executive board appointed by the President. This bank would also modify the loan guarantee program as defined by Energy Policy Act of 2005 by taking control of this function from DOE.

This bank would support several large CCS demonstrations, as well as other promising energy technology development and demonstration. Just like the first two options, this bank would also avoid the federal appropriations process but may not avoid the potentially difficult federal procurement rules.

3.2.2.4. Cost Sharing - CCS Technology Act of 2008

There are several proposals using the government cost sharing method to support CCS demonstration. One recent proposal is S.2323 proposed by Sen. John Kerry of Massachusetts. This bill would provide \$1.6 billion to support 3-5 sequestration demonstration projects, as well as \$2.4b to support 3-5 capture demonstration projects. Up to 50% of the cost of the project could be supported by government funds. The bill also would provide increased levels of CCS R&D up to \$350m for the 2008-2012 period.

4. Financing new coal generation under US public policy

Using the comparison of projected Nth-plant costs of CCS in Section 2, together with projected costs seen for the two major climate regulations discussed in Section 3, a first-order conclusion can be reached on the decision to finance new generation with CCS in the coming years. The CCS cost estimate in Section 2 shows that post-combustion capture on a new supercritical coal plant would cost \$52/tonneCO_2 avoided. Adding in a premium for transportation and storage CO_2 of \$10/tonneCO_2, the total would then be \$62/tonneCO_2. An EIA projection of carbon price resulting from the Bingaman-Specter bill shows a price of \$13/tonneCO_2 by 2020 and \$26/tonneCO_2 by 2030 (core scenario) [18]. A similar analysis for an earlier version of the Lieberman-Warner bill shows a price of \$30/tonneCO_2 by 2020 and \$61/tonneCO_2 by 2030 (core scenario) [19]. The highest carbon price seen would be \$61/tonneCO_2 by 2030 under the Lieberman-Warner bill. Since the Nth-plant estimate of CCS cost is \$62/tonneCO_2, a small \$1/tonneCO_2 gap exists.

A break-even situation for financing Nth-plant CCS would not be reached until 2030 or thereafter, so these two carbon regulations alone would be insufficient to justify large-scale deployment of CCS anytime soon. An even higher carbon price would be required to justify financing first-of-a-kind CCS plants and early demonstrations, which are prerequisites to move CCS technology down the technology learning curve, so that the Nth-plant cost can finally be reached. While both the Lieberman-Warner and Bingaman-Specter bill both contain support for R&D and demonstration of CCS technology, the effect of the R&D and demonstration investment was not modelled in the EIA analysis.

Carbon regulations alone may still be insufficient to deploy CCS in an effective manner to mitigate the effects of climate change. Socolow and Pacala at Princeton propose that 800GW of new coal with CCS must be adopted worldwide by 2054 to fulfil $1/7^{th}$ of the total CO_2 mitigation worldwide by 2054. If the US has only built 5-10 demonstration and first-of-a-kind CCS projects before 2030, the chances of being able to achieve a significant portion of this 800GW goal are very small. Both a stronger carbon regulation and a more aggressive R&D and demonstration program for reducing the cost of CCS must be considered if significant commercial financing and deployment of CCS is desired.

5. Conclusion

This paper provides a financial analysis for new SCPC plants with CCS that compares the effects of two relevant climate policies. First, a cost estimate was presented for new supercritical pulverized coal plants, both with and without CCS. The capital cost escalation of recent years can be attributed to rising materials, plant supply, and plant contractor constraints. This estimate is compared with costs estimates from public sources. Second, several current and proposed public policies relevant to CCS were discussed. Finally, a financial analysis was performed to evaluate the effectiveness of two likely US carbon regulations on deploying Nth-plant CCS technology. The conclusion is that the leading US carbon cap-and-trade bills will likely not be sufficient to deploy CCS technology in a manner consistent with global CO_2 emissions reduction scenarios. A more strict carbon regulation and a more aggressive R&D and demonstration program for reducing the cost of CCS must also be considered.

Appendix A. Cost Estimate Details

500 MWe plant net output; 85% capacity factor; Illinois # 6 coal (61.2% wt C, 10,900 Btu/lb HHV, $1.79/MMBtu); for Oxy-PC CO_2 for sequestration is high purity; for IGCC, GE radiant-cooled gasifier for no-capture case and GE full-quench gasifier for capture case; 20-year payback period.

Notes:
(1) Assume Nth plant where N is less than 10 (assumes significant cost reduction from learning in construction/operation)
(2) Efficiency = 3414 Btu/kWe-h /(Heat rate in Btu/kWe-h)
(3) Annual carrying charge of 15.1% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge
(4) Does not include costs associated with transportation and injection/storage.

Appendix B. Acknowledgements

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